Planning Guidelines for Integrating DSM with T&D Planning

In the normal planning process, the utility has an obligation to

1. design the T&D system to meet normal loads,
2. design the T&D system to meet first-contingency loads, where justified and feasible, given the density and spatial distribution of load, and
3. if a problem is experienced or projected, to re-configure the system to meet loads at the lowest feasible cost before any equipment upgrades are contemplated.

This appendix discusses the process for expanding the T&D planning process to include options for using DSM and distributed generation to reduce the cost of maintaining the reliability of power delivery.

1. Identify areas with T&D supply problems.
   a) Identify areas (usually defined by substation or feeder number) in which major T&D investments are planned or projected. Look forward a minimum of 10 years, to maximize the number of situations in which DSM will have sufficient time to work.
   b) Identify the Critical Load Element (CLE)—the feeder, substation, or transmission line that is expected to be overloaded in the absence of T&D reinforcement.
2. Define the Region of Opportunity (ROO) in which load reductions could contribute to deferring the need for the reinforcement.
   a) The ROO includes both areas served by the CLE and areas served by equipment that can pick up load from the CLE.[1] In other words, determine if load reductions on other T&D facilities can permit load to be shifted off the CLE.[2]

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[1] Figure 1 illustrates this point. Assume that the Company is planning to upgrade Feeder 1 and Substation 4 (or the transmission lines serving that substation).

[2] The extent of re-configuration of the distribution system is limited by reliability and cost considerations, such as effect on losses and power factor.

b) If the CLE is a feeder the ROO includes the area served by the feeder and its laterals or taps, and potentially

i) parallel feeders close to laterals or taps that run from the CLE. If a parallel feeder can pick up some of the load by shifting laterals or taps to that feeder (e.g., from Feeder 1 to Feeder 2 in Figure 1), include it in the ROO.

ii) feeders that are connected to the end of the CLE through a normally open switch. If some of the length of the CLE can be shifted to another feeder by relocating the normally open switch closer to the origin of feeder 1 (e.g., Feeder 3 in Figure 1), the ROO includes the areas served by that second feeder.

c) If the CLE is a distribution substation, the potential ROO includes

i) the area normally served by the feeders from that substation;

ii) the entire area normally served by other substations serving feeders that can take load off the feeders served by the CLE (e.g., Substation 5 in Figure 1) in either of the ways described above.

d) If the CLE is a transmission line (or substation), the potential ROO includes

i) the area downstream from the CLE,[3] and

ii) the area served by any transmission line (or substation) that can pick up load from the CLE

a) directly by serving a distribution substation currently downstream of the CLE, or

b) indirectly by transfer of feeders loads from substations on the CLE to substations on the alternative line.

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[3] For transmission lines served at both ends, “downstream” is defined for the conditions creating the critical load.

e) If the critical load is a first-contingency overload, include in the relevant area all of the circuits that contribute to a first-contingency overload on the CLE.[4] In particular, consider:

i) All feeders connected to the end of CLE through a normally open switch (Feeder 3 in Figure 1),

ii) All feeders parallel to the CLE, and

iii) All feeders parallel to feeders connected to the end of the CLE through a normally open switch (feeders parallel to Feeder 3 in Figure 1).

f) Consider the option of using other utilities' facilities to serve load.

i) Alternative substations and feeders should not be ignored by the utility just because they are owned by other companies.

ii) Coordination of targeted DSM on adjacent facilities of different utilities may allow for deferral of facilities planned by one or more utilities.

3. Identify deferrable costs and the DSM load reductions that would be needed to defer those costs for various periods of time.[5]

a) Specify the magnitude, shape and timing of the load reduction necessary to avoid T&D expenditures.

i) Use the area load forecast on which project planning is based.

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[4] The adequacy of each major T&D facility (transmission line, substation transformer, or feeder) is generally assessed by modeling the effect of the "first contingency" for the equipment—the loss of the piece of equipment that would shift the maximum load onto the facility under review. For example, if Feeder 3 in Figure 1 experienced an outage near its middle (e.g., a conductor breaks), normally closed switches around the fault would open up, the normally open switch with Feeder 1 would close, and the loads on the far end of Feeder 3 would be picked up by Feeder 1. Both Feeder 1 and its substation transformer must be able to handle the higher load for several hours, until the fault is repaired and Feeder 3 returns to service.

[5] In general, distributed generation can be treated as a type of targeted DSM. Planning differences between DSM and distributed generation are discussed below.

ii) Determine which peaks and other high load hours affect the overloading problem.[6]

b) Some projects involve both a non-load-related action (such as replacing aging poles or conductors) and a load-related action (such as increasing conductor sizing or increasing primary voltage). DSM may not be able to defer the non-load-related action, but may reduce the cost of the project by avoiding the load-related component. Ask the question: What portion of the cost of the project can be deferred or eliminated if loads remain at current levels or are reduced from projected levels?

c) DSM may be able to avoid the T&D project permanently or delay it, depending upon the pattern of load growth and the DSM potential. Figures 2a and 2b illustrate both cases.

i) Figure 2a describes an area projected to experience a one-time spurt of load growth in the year 2000, but minor load growth before then or after (as illustrated in Figure 2a). Assume that the existing distribution capacity or small conservation programs could accommodate the minor growth, but not the entire 7.5 MVA jump in load in 2001.[7] Cumulative DSM reductions of 2.5 MVA by 2001 will avoid the T&D expansion permanently; anything less will neither avoid nor delay the expenditure.

ii) Figure 2b describes an area with steady load growth with T&D system that will become overloaded in 2001 (as illustrated in Figure 2b). A cumulative DSM reduction of 2 MVA by 2001 will permit a one-year delay, a reduction of 4 MVA by 2002 will permit a two-year delay, and so on. If at some point, DSM implementation cannot keep pace with load growth, the T&D upgrade will be needed.

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[6] Generally, targeted DSM involves peak reductions in the same diurnal period at various feeders in the ROO. However, shifting load to avoid an overload in one hour could cause problems in another hour. For example, a winter evening peak problem on one feeder may be alleviated by shifting load to an adjacent feeder with low evening loads, but this action may result in a new morning peak overload problem on the second feeder.

[7]DSM programs designed to meet a low rate of load growth are certainly feasible.

d) With continuous load growth, longer deferrals will require larger DSM reductions per year. For example, for the scenario illustrated in Figure 2b, a one-year delay in the 2001 project requires a DSM reduction of 0.33 MVA per year, if the DSM programs are implemented in 1997; a two-year delay requires a reduction of 0.6 MVA per year, a five-year delay requires a reductions of 1 MVA per year. Over time, it will become more and more difficult to obtain DSM savings in time to avoid facility overloading. At some point, the T&D upgrade will be required.

e) To the extent feasible, the economic analysis of targeted DSM should include all foreseeable effects on T&D timing. With continuous load growth, additional components (feeders, distribution substations, transmission lines) may become overloaded over time. The value of the DSM implemented to defer addition of a feeder in 1999 may also contribute to deferring an expansion of substation capacity in 2003 and transmission capacity in 2005.

4. Compute the benefits of DSM load reductions:

a) In cases where the entire T&D expenditure is avoided, determine the total present value revenue requirements (PVRR) including O&M and net of any change in losses.

b) In cases where the T&D expenditure is deferred, determine the value of delaying the project one year (the capital investment times the real-levelized carrying charge, plus O&M, net of any change in losses).[8]

c) Using (a), compute the total present value of cost deferral as a function of the number of years of deferral (as illustrated in Table 1).

d) To the area-specific T&D value, add the value of avoided energy (avoided fuel, opportunity for increased off-system sales, capitalized energy), avoided generation capacity (with required reserve margin), and residual T&D (defined below).[9] Include all

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[8] The change in losses should be calculated at current load levels.

[9] If re-configuration of the T&D system to take advantage of DSM affects losses or other costs, these changes should be taken into account in the computation of DSM benefits.

benefits of load reductions, regardless of whether the reductions are coincident with the loads that drive the T&D expansion.

5. Seek targeted DSM retrofit, enhanced lost-opportunity programs, and distributed generation to relieve congestion.

    a) Look for packages of DSM and DG with necessary scale and low enough costs.

    b) For DSM retrofit programs, consider the timing of the DSM implementation and load reductions. The present value costs of the DSM will be lower if its implementation is spread out to match the load growth.

    c) Lost opportunities, on the other hand, should be acquired when they arise.

    d) Use the area load forecast on which T&D plans are based to forecast DSM potential.

6. Compute residual non-area-specific T&D benefits resulting from targeted DSM savings. Those non-specific T&D benefits can be estimated as all load-related T&D investments and associated O&M, minus the targeted project in the period for which specific budgets have been prepared.

7. In addition to the specific T&D projects selected for distributed IRP, avoidable T&D costs include:

    a) Avoided transmission costs that are affected by loads over a large portion of the service territory, including

        i) Upgrades in bulk transmission and interconnection facilities, such as:

            a) VELCo transmission

            b) All transmission substations

            c) All transmission lines that do not go to distribution substations

        ii) Market value of surplus transmission capacity that can be made available for wheeling power through Vermont.

b) The energy-related benefits of increased equipment life. The longevity of the insulation on lines and transformers is reduced by near-peak loads and high energy loadings, so just about any type of load reduction will have some T&D benefit.

c) Deferrable distribution costs best dealt with on an average basis, because they are widely dispersed, or the equipment is too small to be analyzed as individual targeted projects:

   i) minor load-related additions (usually projected from blanket budget authorizations)

   ii) primary lines below feeders (laterals or taps)

   iii) line transformers

   iv) secondary lines

   v) capacitors

   vi) service-drop upgrades

d) Those non-specific T&D benefits can be estimated as all load-related T&D investments and associated O&M, minus the targeted projects in the period for which specific budgets have been prepared.

   i) For the 10-year period for which T&D budgets existing, the non-specific T&D avoided costs used for distributed IRP analyses should equal the system-wide avoided T&D, minus the T&D projects selected for targeting.

   ii) Beyond the T&D-budget period, the non-specific T&D avoided costs should equal the system-wide avoided T&D costs.

8. While targeted DG is generally an alternative to new T&D investment quite comparable to targeted DSM, it characteristics vary from that of DSM in several ways.

   a) DG additions may require some re-design of the T&D system. If DG capacity exceeds local loads, power will flow back into the distribution system, potentially increasing load at some critical point on the distribution circuit. Small units are unlikely to have this effect. DG is most like DSM when there is a multiplicity of small units located at individual customer sites with minimal power flows out of the site.

b) Utilities can locate DG with more specificity than they can DSM.

c) DG may improve (or in some cases degrade) power quality.

d) DG located at the customer site can improve reliability of service to that customer.[10]

e) Once installed, DG is subject to outages, making it less reliable than DSM. Depending on the availability of the DG, it may provide higher or lower reliability to customers on the distribution circuit than would the expansion of T&D capacity.

f) With sufficient preparation, DG can have a shorter lead-time than DSM.

9. In evaluating options (T&D facility versus DSM, DG, or use of another utility's facilities), utilities should consider and report important differences in environmental and aesthetic effects.

   a) If the selected option has greater impacts than the alternative, the utility should specify (and where possible quantify) the cost, reliability, and other benefits that the utility believes outweigh the environmental effects.

10. If a probabilistic model or decision analysis is used to assess the cost-effectiveness of alternatives to T&D investment, the analysis should:

   a) Recognize that DSM reduces load growth uncertainty.

   b) Recognize that DSM potential increases with load growth.

   c) Include a decision period that is long enough to permit consideration of (i) DSM and other options with long lead-times and (ii) the appropriate timing of the T&D investment.

   d) Include an analysis period (or end effects) sufficient to capture the rising long-term resource benefits of DSM.

   e) Allow deferral, as well as cancellation, of the T&D options.

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[10] Maximizing reliability benefits requires that the DG be configured to operate when the T&D system is out of service.

f) If the cost of targeted DSM is to be compared to the cost of T&D (as opposed to computing the maximum price that can be paid for targeted DSM, as described above),

   i) Credit DSM with all energy, generation capacity, and residual T&D benefits over the entire year, not just during critical hours on the CLE.

   ii) Include reasonable estimates of DSM potential at various prices and over various time frames.